









DCUSA Consultation		At what stage is this document in the process?
<h1>DCP 284</h1> <h2>The application of scaling to generation credits in the CDCM</h2> <p>12 October 2016</p> <p>Standard Change</p>		01 – Change Proposal
		02 – Consultation
		03 – Change Report
		04 – Change Declaration
<p><b>Purpose of Change Proposal:</b></p> <p>DCP 284 seeks to amend the calculation of credits for embedded generation to more closely reflect the benefits they bring to Distribution Network Operators by including an element of scaling.</p> <p>This document is a Consultation issued to DCUSA Parties and any other interested Parties in accordance with Clause 11.14 of the DCUSA seeking industry views on DCP 284.</p>		
	<p>The Working Group recommends that this Change Proposal should proceed to Consultation.</p>	
	<p>Parties are invited to consider the questions set in section 10 and submit comments using the form attached as Attachment 2 to <a href="mailto:dcusa@electralink.co.uk">dcusa@electralink.co.uk</a> by <b>27 February 2017</b></p>	
	<p>The Working Group will consider the consultation responses and determine the appropriate next steps for the progression of the Change Proposal (CP).</p>	
	<p>Impacted Parties: Distribution Network Operators (DNOs), Generators, Suppliers</p>	
	<p>Impacted Clauses: Schedule 16 (CDCM), Schedule 20 (Production of the Annual Review Pack)</p>	

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Timetable		
The timetable for the progression of the CP is as follows:		
<b>Change Proposal timetable</b>		
<b>Change Proposal timetable:</b>		
Activity	Date	
Initial Assessment Report Approved by Panel	19 October 2016	
Consultation issued to Parties	6 February 2017	
Change Report issued to Panel	17 May 2017	
Change Report issued for Voting	19 May 2017	
Party Voting Ends	9 June 2017	
Change Declaration Issued to Parties	13 June 2017	
Change Declaration issued to Authority	13 June 2017	
Authority Decision	18 July 2017	
Proposed Implementation Date	01 April 2019	

## 1. Summary

### What?

- 1.1 The Distribution Connection and Use of System Agreement (DCUSA) is a multi-party contract between electricity Distributors and electricity Suppliers and Generators. Parties to the DCUSA can raise Change Proposals (CPs) to amend the Agreement with the consent of other Parties and (where applicable) the Authority.

### Why?

- 1.2 DCP 284 (attachment 1) has been raised by MVV Environment Services Ltd. and is seeking to address the issue of whether scaling or some element of scaling should be applied to credits for embedded generation within the CDCM. Scaling is an alternative word used to mean revenue matching. Revenue matching takes the pre-scaled tariffs and amends them to match each DNO's allowed revenue. The proposer suggests that the application of scaling when determining credits under the CDCM could improve the cost reflectivity of generation credits for embedded generators. The proposer believes that some costs are omitted from the yard stick tariffs that are used to derive generation credits and these costs could be reduced through the presence of embedded generation. The proposer believes these costs are captured through scaling and the scaling elements should therefore be included in generation credits. More cost reflective credits for generators will place incentives on embedded generation that reflect the benefits they bring to network operators.

### How?

- 1.3 The proposed solution is to apply a percentage of scaling when calculating credits for embedded generators in the CDCM.

## 2 Governance

### Justification for Part 1 Matter

- 2.1 DCP 284 is classified as a Part 1 matter and therefore will go to the Authority for determination after the voting process has completed.
- 2.2 This issue is considered a Part 1 Matter as it affects the level of charges for embedded generation and therefore impacts on competition for embedded generation as specified under DCUSA clause 9.4.2 (A).

## Requested Next Steps

Following a review of the Consultation responses, the Working Group will work to agree the detail of the solution for DCP 284.

### 3 Why Change?

#### Background of DCP 284

- 3.1 Under the CDCM, generation credits reflect demand charges at voltage levels above the voltage of connection, except for the application of scaling. It is the proposer's view that during the development of the CDCM, scaling was excluded from the derivation of credits as the costs included within scaling were not seen to be avoided through the presence of embedded generation.
- 3.2 The recent DCUSA CP (DCP228<sup>1</sup>), approved by the Authority, amends the way in which scaling is applied to demand charges.
- 3.3 The DCP 228 change report provides the following comment on scaling:  
  
*"DCP 228 is intended to be clearer in explaining that the shortfall or excess of revenue recovered from pre-scaled yardstick tariffs is a natural consequence of the incremental design of the CDCM. As the accompanying spreadsheet demonstrates, the CDCM recovers significantly more in peak charges than DNOs expect to spend on network reinforcement for the foreseeable future. This is because the CDCM provides incremental cost signals rather than total cost signals. Similarly, there are DNO costs which are not included in the CDCM (such as replacement costs and a portion of indirect costs), however these are not 'unidentified' as the DCP 123 form suggested, but rather they are intentionally excluded from the CDCM for the purpose of deriving the desired incremental cost signals. This CP is therefore clear in its intent that scaling should not be used to allocate any cost not included within the CDCM, but should rather be applied in a way which maintains the incremental cost signals produced by the pre-scaled tariffs."*
- 3.4 It is the proposer's view that this CP considers the costs associated with the replacement of assets within scaling which, although it may not be an incremental cost for demand customers, is potentially an area of saving for DNOs through the connection of embedded generation.
- 3.5 It is also the proposer's view that DNOs replace assets as they reach the end of their useful life. If embedded generation is installed, then the potential benefit to the DNO is that the asset may not need to be replaced as it is no longer required or the asset can be replaced with a smaller capacity asset which is therefore cheaper. The degree to which this occurs will vary depending on the type of generation, the degree to which it can be relied upon by the DNO and the arrangement of the network to which the generator is connected.

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<sup>1</sup> DCP228 - ['Revenue Matching in the CDCM'](#)

- 3.6 DCP 284 was raised by MVV Environment Services Ltd. and seeks to amend the calculation of credits for embedded generation to more closely reflect the benefits they bring to DNOs by including an element of scaling. It proposes to allocate an element of the scaling to generation by applying 50% of scaling as generation credits. The proposer however considers that this value should be determined by the Working Group after undertaking analysis in this area.

## 4 Code Specific Matters

### Reference Documents

n/a.

## 5 Working Group Assessment

### DCP 284 Working Group Assessment

- 5.1 The DCUSA Panel established a Working Group to assess DCP 284. This Working Group consists of DNO, Supplier, National Grid and Ofgem representatives. Meetings were held in open session and the minutes and papers of each meeting are available on the DCUSA website – [www.dcusa.co.uk](http://www.dcusa.co.uk).
- 5.2 The Working Group discussed whether scaling, or some element of scaling, should be applied to credits for embedded generation within the CDCM taking in to consideration the approaches taken in two previous CPs, DCP 123<sup>2</sup> and DCP 228.
- 5.3 The Working Group questioned the reasoning provided by the proposer within the CP form which is quoted below.
- *“The recent DCUSA change proposal (DCP228) that has been approved by the Authority amends the way in which scaling is applied to demand charges. This change proposal provided more detail on what costs are recovered via scaling.”*
  - *“The DCP 228 change report identified the costs that are recovered via scaling mainly comprise of asset replacement and a portion of indirect costs.”*
- 5.4 The Working Group considered that the approach to DCP 228 was clear in its intent that scaling should not be used to allocate any cost not included within the CDCM, but should rather be applied in a way which maintains the incremental cost signals produced by the pre-scaled tariffs. The CDCM model is not a total cost model so the rationale set out in DCP 228 would not necessarily be applicable for this CP. It was also noted that DCP 123 had been rejected by the Authority, partly because it was attempting to allocate costs through the scaling mechanism without demonstrating that scaling had been spread in a more cost reflective way.

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<sup>2</sup> DCP 123 [‘Revenue Matching Methodology Change’](#)

5.5 The Working Group considered any reasons behind why generation is excluded and demand included for scaling purposes. Members suggested that the yardstick costs are underlying cost signals and scaling was preserving those cost signals and as such there would be no impact on the network if generators were responding to those scaling elements.

5.6 The approach to scaling within the CDCM was discussed with Ofgem prior to the implementation of DCP 059<sup>3</sup> in DCUSA on the 01 April 2010. During the development of the CDCM, Ofgem had expressed a preference for scaling to be applied to generation in the same way as it is applied to demand. The method preferred by Ofgem was labelled as “Option B” and was defined as follows:

*Option B: A single adder is calculated, added to tariffs for demand users, and deducted from credits paid to generation users (or if the adder is greater than the credit, then a charge is made to the generator equal to the adder less the credit).*

5.7 However, the approach proposed by DNOs at the time was labelled as “Option C” and defined as follows:

*Option C: A single adder is calculated and used for demand, and no revenue reconciliation element is included in generation tariffs (credits paid to generators are equal to the yardstick avoided cost figure).*

5.8 The DNOs submitted a methodology to Ofgem based on Option C, as they saw this as a more appropriate methodology.

5.9 The Ofgem consultation document on the proposed CDCM considered whether scaling should apply to generation. The Working Group considered that the extracts shown below are relevant to this CP:

**Ofgem consultation document on Electricity distribution structure of charges project: DNOs' proposals for a common methodology at lower voltages<sup>4</sup>**

*'2.60. We note that the revenue matching mechanism in the CDCM does not apply to generators. This means that charges/credits to generators remain at their pre-scaling level. Although it is difficult to identify precisely what the discrepancy represents, a shortfall to some extent covers non-incremental overhead costs. We see no obvious reason why DGs<sup>5</sup> should be excluded from such cost.'*

*Following the consultation Ofgem produced a decision document, one aspect of which, was how scaling would be applied. Ofgem recommended that this should be taken forward under open governance.*

**Ofgem decision document on Electricity distribution structure of charges project: the common distribution charging methodology at lower voltages<sup>6</sup>**

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<sup>3</sup> DCP059 - [Implementation of Common Distribution Charging Methodology \(CDCM\)](#)

<sup>4</sup> [Ofgem's consultation document on Electricity distribution structure of charges project: DNOs' proposals for a common methodology at lower voltages](#)

<sup>5</sup> Distributed Generator (DG)

<sup>6</sup> [Ofgem's decision document on Electricity distribution structure of charges project: the common distribution charging methodology at lower voltages](#)

*'2.37. A bottom-up charging methodology requires a mechanism to scale charges to match the recovered revenue from the model with the permitted price control revenue. The DNOs decided to exclude generators from the revenue matching process, meaning charges/credits to generators remain at their pre-scaling level.'*

*'2.38. The proposal does not provide any justification for the decision to exclude generators from scaling and we would expect this matter to be addressed through open governance arrangements. We see no obvious reason why DGs should be excluded from this mechanism.'*

- 5.10 There were two differing views within the Working Group regarding the purpose of scaling, with some members believing that scaling is a means of taking the cost signals derived from the pre-scaled tariffs and maintaining them whilst ensuring the DNO targets allowed revenue, and others believing that scaling was the means by which certain costs which are not included in the underlying inputs to the CDCM are recovered.
- 5.11 To support the former view there is a belief (as set out in DCP 228) that scaling was not used to allocate specific costs, but was rather a means of maintaining the cost signals generated by pre-scaled tariffs whilst ensuring the DNO recovers their allowed revenue. That is, the costs included in the DNOs 500MW model, service models and direct/indirect costs are used to generate a set of pre-scaled tariffs with the desired differentials between tariff elements. Scaling is then a means of maintaining this differential between tariff elements whilst enabling the DNO to target allowed revenue. As such, scaling is not a means of allocating costs, and it is not a true representation of scaling to analyse which costs are included in the underlying inputs and conclude that the remainder of costs are allocated by scaling; rather the underlying inputs are intentionally used (and certain elements intentionally excluded) to provide the appropriate cost signal, which scaling then seeks to maintain.

**Do you accept the interpretation of scaling provided in paragraph 5.11? Provide your rationale for your response.**

- 5.12 It is therefore appropriate for this CP to consider applying scaling to generation credits in one of three ways:
- a) Apply scaling in the same direction as scaling is applied to demand using the same fixed adder, i.e. in the case where pre-scaled tariffs would generate a revenue shortfall, the demand fixed adder would be positive and so generation scaling would also be positive, resulting in smaller credits. This approach would have the advantage of maintaining the absolute pre-scaled differential between demand and generation tariffs, in the same way as DCP 228 maintained the absolute differential between unit rates within each tariff.
  - b) Apply scaling in the opposite direction to scaling is applied to demand using the same fixed adder, i.e. in the case where pre-scaled tariffs would generate a revenue shortfall, the demand fixed adder would be positive and so generation scaling would be negative, resulting in larger credits. This approach would effectively set the generation credits to be the negative of post-scaled demand charges (at voltages above but not including the voltage of connection); where at present generation credits are set to the negative of pre-scaled demand charges. This approach would result in higher demand charges.

c) Apply neutral scaling to generation credits, i.e. the status quo.

5.13 Under options a and b, consideration would need to be given to capping generation credits at zero (so that they are always negative) in the same way as DCP 228 capped demand charges at zero in instances where pre-scaled tariffs would generate a revenue surplus.

**Under the interpretation provided in paragraphs 5.12 and 5.13, should scaling be applied to generation in the same direction as demand (option a), the opposite direction to demand (option b) or neutral (option c)? Please provide your rationale for your response.**

5.14 The proposer's view is that the CDCM model uses scaling to recover the additional costs that are not recovered through the yardstick tariffs and that these costs can be identified. The proposer notes that the CDCM model produces tariffs based on a range of inputs. The inputs that relate to costs can be split into two categories:

- Forward looking costs – these are the DNO's forecast of the costs likely to be incurred in the applicable charging year. These include direct costs, indirect costs, network rates and transmission exit charges (CDCM tables 1055 and 1059) and are used to derive operational incremental cost signals.
- 500MW model costs – these costs represent the hypothetical cost of building new network. This is based on a 500MW model which determines the hypothetical cost of building a distribution network capable of a 500MW maximum demand (CDCM table 1020) and is used to derive reinforcement incremental cost signals.

5.15 In summary, these could be considered as non-capital and capital costs.

5.16 The proposer notes that the non-capital costs are recovered directly via the yardstick tariffs and this can be seen in the CDCM "M-Rev" tab (table 3902) which shows how much revenue is recovered from tariffs separated by cost category. The proposer therefore asserts that these cost elements are recovered within the yardstick tariffs and therefore are not part of scaling. The only exception is the 40% of indirect costs which is excluded from this calculation and therefore must be recovered within the scaling element.

5.17 The proposer notes that the capital cost element from the 500MW model is not a forecast cost for the charging year. Rather it is the cost of a hypothetical model which is deemed to be representative of the capital expenditure of the DNO. The actual DNO's capital expenditure is normally more, but in some cases it is less and that is why negative scaling results in some DNO areas. The proposer therefore asserts that the scaling element of the tariffs can be considered to consist of:

- The difference between the actual capital cost of the DNO (on an annualised basis) and the hypothetical cost of building new network from the 500MW model (which may be positive or negative)
- 40% of indirect costs (as identified in 5.16 above)
- Other costs such as incentive schemes and cost true ups from previous years.



**Do you support the view of the proposer provided in paragraphs 5.14 to 5.17 on how scaling is applied? Please provide your rationale for your response.**

5.18 The scaling overview below has been provided by the proposer and provides an analysis of what cost components the proposer believes are recovered directly from the yardstick tariffs in the CDCM model and those elements recovered via scaling. This includes the proposer's view on why there are differences between the 500MW model and the actual capital expenditure (on an annualised basis) which is recovered from scaling.

## Scaling Overview

5.19 The tables below show how much revenue is recovered through scaling and how much is recovered through the different cost components of the final tariff. It should be noted that the operating cost component consists of network costs, direct costs and 60% of the indirect costs.

**Table 1 – Breakdown of costs for 2016/17**

DNO	Allowed Revenue (£m)	Costs recovered through charges (£m)			
		Non-capital		Capital	Scaling
		Operating costs	Transmission Exit charge	Asset Costs	
ENWL	£430.0	£112.7	£18.3	£166.4	£132.6
NPG Northeast	£283.9	£76.6	£10.8	£69.4	£127.1
NPG Yorkshire	£357.7	£103.7	£13.6	£97.4	£143.0
SPEN SPD	£385.4	£120.9	£24.1	£90.6	£149.8
SPEN SPM	£314.9	£109.0	£19.1	£106.9	£79.9
SSEN SEPD	£548.8	£153.5	£15.9	£211.9	£167.5
SSEN SHEPD	£236.8	£93.8	£14.1	£40.3	£88.8
UKPN EPN	£545.8	£190.9	£37.4	£278.0	£39.4
UKPN LPN	£412.3	£128.1	£35.8	£306.2	-£57.9
UKPN SPN	£378.7	£114.4	£17.6	£155.8	£90.8
WPD EastM	£453.5	£127.6	£11.1	£140.1	£174.8
WPD SWales	£220.4	£71.3	£11.2	£41.0	£96.9
WPD SWest	£331.0	£101.0	£8.7	£53.1	£168.2
WPD WestM	£479.3	£121.6	£11.6	£128.8	£217.3

## Scaling components

5.20 There have been a number of DCUSA change proposals that looked at how scaling is applied and what cost elements are recovered within scaling. The proposers view, as stated in 5.16 above, is that scaling recovers 40% of indirect costs and the difference between the actual DNO capital expenditure (on an annualised basis) and the capital expenditure assumed within the hypothetical 500MW model.

## Indirect Costs

5.21 Indirect costs are split using an indirect cost proportion of 60%. This means that 60% of the total indirect costs within the CDCM are allocated and form part of the operating costs component of the tariff. Consequently, the 40% of indirects is not recovered elsewhere, so the proposer asserts that it must be recovered within the scaling element. The tables below show the residual element of scaling that is left, once 40% of the indirect costs are removed. The table also shows the ratio of the residual scaling to the original scaling.

**Table 2 - Residual Scaling for 2016/17 (£m)**

DNO	Scaling	40% of Indirect Costs	Residual Scaling	Percentage
ENWL	£132.6	£39.0	£93.6	71%
NPG Northeast	£127.1	£30.5	£96.6	76%
NPG Yorkshire	£143.0	£35.3	£107.8	75%
SPEN SPD	£149.8	£42.8	£107.0	71%
SPEN SPM	£79.9	£43.8	£36.1	45%
SSEN SEPD	£167.5	£42.7	£124.8	75%
SSEN SHEPD	£88.8	£23.3	£65.5	74%
UKPN EPN	£39.4	£67.5	-£28.1	-71%
UKPN LPN	-£57.9	£49.3	-£107.2	-185%
UKPN SPN	£90.8	£43.7	£47.2	52%
WPD EastM	£174.8	£44.2	£130.5	75%
WPD SWales	£96.9	£24.6	£72.3	75%
WPD SWest	£168.2	£39.0	£129.2	77%
WPD WestM	£217.3	£45.2	£172.1	79%
<b>Total</b>	<b>£1,618.3</b>	<b>£571.0</b>	<b>£1,047.3</b>	<b>65%</b>

5.22 It can be observed from the residual scaling in 2016 /17 that two of the UKPN areas have negative scaling once 40% of the indirect costs have been removed. The proportion of the residual scaling to the original scaling for most DNOs falls in the range of 45% to 79%. The reason for negative values for one DNO is the difference between 500MW model and actual capital expenditure.

5.23 The proposer believes that the proportion of indirect costs (40%) that are currently excluded from the yardstick tariffs and recovered via scaling should not be applied as either a charge or a credit to

embedded generation. This element of indirect costs has been excluded from the yardstick tariff as it is not considered by the proposer to vary with the level of demand. Under the RIIO price control settlement, indirect costs are split into:

- Closely Associated Indirects
- Business Support Costs
- Non-operational capex costs

5.24 The proposer believes the business support costs and non-operational capex costs are the most likely to be recovered via the 40% on indirect costs that are included in scaling and these recover the following cost elements;

Business Support Costs comprise the following five categories:

- Finance and regulation
- HR and non-operational training
- Property management
- CEO and group management
- IT & telecoms

Non-operational capex costs comprise the following four activities:

- property
- small tools, equipment, plant and machinery
- IT&T
- vehicles and transport

5.25 The proposer asserts that these cost elements when considered overall are not impacted by the presence of embedded generation. This is because the distribution networks continue to be demand dominated and embedded generation is contributing to reducing the size of the networks. The indirect costs are costs associated with providing a distribution network which primarily exists to serve demand customers and therefore the indirect costs listed above should be recovered from demand customers only. Where part of the distribution networks has potential to become generation dominated, the output of the embedded generation tends to be curtailed under active network management schemes resulting in no reinforcement costs on behalf of the DNO and preventing the network from becoming generation dominated. It should be noted that DNOs brought forward a DCUSA change proposal<sup>7</sup> to reduce or remove credits for embedded generation in generation dominated areas and this was rejected by Ofgem in 2015.

5.26 In addition, a further cost that is not demand related and likely to fall into the 40% of indirect costs is the pension deficits for each DNO. These deficits are historical in nature and can be substantial. The deficits exist due to the historical pension arrangements of DNOs and relate to the development of the distribution networks which primarily serve demand customers. It therefore does not seem appropriate that embedded generation should either contribute to the costs of these pensions or benefit from offsetting them.

## Residual scaling

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<sup>7</sup> [DCP 137 - Introduction of locational tariffs for the export from HV generators in areas identified as generation dominated.](#)

5.27 The proposer suggests in the change proposal that the residual scaling largely consists of asset replacement and that embedded generation can lead to cost savings for DNOs in this area. Where embedded generation is installed then the potential benefit to the DNO is that the asset may not need to be replaced as it is no longer required or the asset can be replaced with a smaller capacity asset which is therefore cheaper.

5.28 As stated earlier, the residual scaling represents the remaining adjustment once direct costs, indirect costs, network rates, transmission exit charges and the 500MW model costs have been removed. The 500MW model sets down the assets needed to build a hypothetical network capable of meeting a peak demand of 500MW and recovers more than the reinforcement costs of DNOs (as specified in DCP228 – see 3.3). The proposer believes that this additional cost equates to asset replacement within the actual allowed revenue of the DNOs. However, the proposer believes that the asset replacement revenue included within the 500MW model understates the actual level of asset replacement which is included in the allowed revenues of DNOs because it is a hypothetical model.

5.29 The proposer suggests that the difference in asset costs between the 500MW model and that assumed within the allowed revenue of DNOs arises due to the following key reasons:

- The 500MW model is a hypothetical model and does not fully reflect the inefficiencies within the actual DNO network. These inefficiencies will arise due to the DNOs' networks evolving over a long period with customers changing their consumption patterns and impacting on locational powerflows.
- The CDCM model assumes a 40-year depreciation period. In reality there will be a range of depreciation timeframes for existing assets. In particular, underground cables can remain in use for over 40 years, and at the other extreme, automation assets that are currently being implemented as part of the move to smart networks are likely to have a much shorter lifespan than 40 years
- The existing DNO network is built based on the design standards that were appropriate at the time of construction. This compares with the 500MW model which is constructed based upon the most up to date design practices
- Ofgem have identified that there is a lack of commonality within the 500MW model and a DCUSA change proposal<sup>8</sup> was brought forward to address this issue. However, the proposed solution was rejected by Ofgem, sighting the following as their reason:

*'This modification proposes the use of a common 500MW model by all Distribution Network Operators (DNOs) rather than using company specific models. However, it does not provide evidence to support the case that the use of a common 500MW model would improve the methodology when judged against the charging objectives.'*

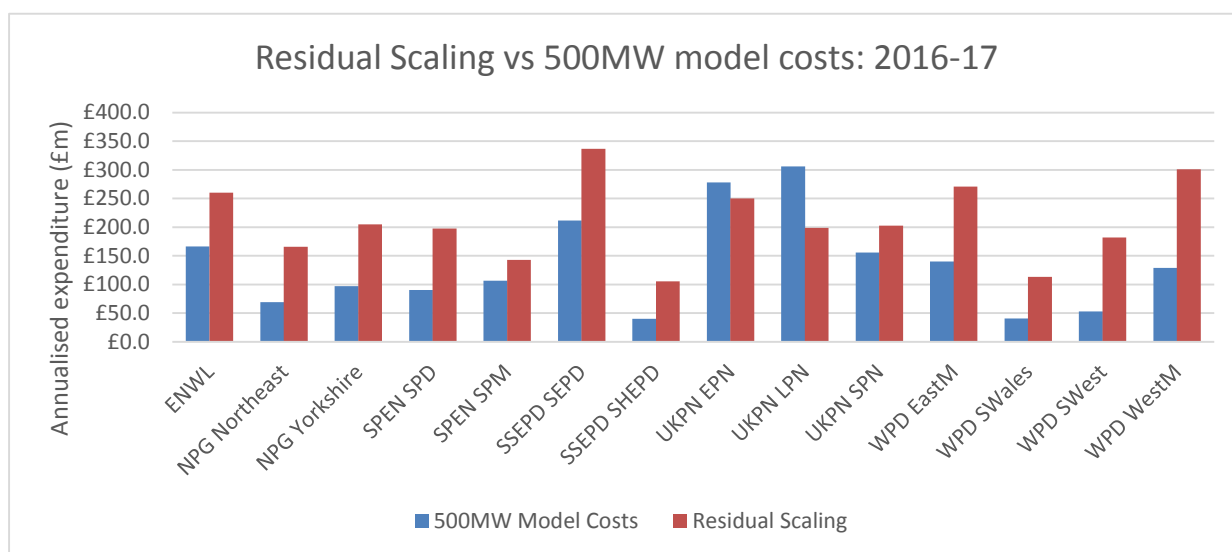
**Do you agree with the definition of residual scaling provided in paragraphs 5.27 and 5.28?  
Please provide your rationale for your response.**

<sup>8</sup> [DCP133 – 500MW network common model for the CDCM](#)

## Residual scaling and embedded generation

5.30 DCP 284 raises the issue of whether scaling should apply to generation credits within the CDCM. The proposer recognises that indirect costs do not vary with demand and are not avoidable by embedded generators. The proposer is therefore questioning whether the residual scaling should form part of the credits for embedded generation.

5.31 The CDCM model can be used to derive a comparison of forecast annualised capex based on the historical values (i.e. derived from the allowed revenue) and the future annualised capex based on the 500MW model. The graph below shows a comparison of these two data sets for 2016 and 2017.



5.32 This graph shows a large difference in the residual scaling elements and the forecast capex using the 500MW model. In most cases the former is higher, except for the UKPN London and Eastern areas. Based on this data, forecast annual capex from the 500MW model is £1.9bn compared to the total residual scaling of £2.9bn in 2016/17, a reduction of 35%.

5.33 The proposer believes that the 500MW model is not reflective of the costs offset by embedded generation and that using the current level of capex by including scaling within the credits for embedded generation is more representative for the following reasons:

- Using actual annualised capex captures the reality of each DNOs network and any inefficiencies that may exist due to how the network has evolved over a long period of time.
- Historical totex used as a proxy for capex across DPCR5 and RIIO-ED1 is fairly constant as shown in the table below and DNOs are not expecting a large reduction in capex across RIIO-ED1 compared to DPCR5.
- The large variation across the DNOs between forecast and actual capex (particularly with some DNOs forecasting higher future capex within their 500MW model) implies some inconsistency in the 500MW model across the DNOs.

- Future capex may be lower than the current ongoing capex in part due to the presence of embedded generation. It is therefore appropriate to reward embedded generation based on current capex, to ensure future savings are captured.

**Is the current level of capex or the 500MW model a better indication of the avoided cost of embedded generation? Please provide your rationale for your response.**

**Table 3 - Ofgem final determination - Average annual DPCR5 and RIIO-ED1 costs by DNO (2012-13 prices)**

DNO	DPCR5 totex (based on 4yrs actual)	DPCR5 totex (based on 4yrs actual, 1y forecast)	Slow-track final determinations allowance post IQI*	Difference (RIIO-ED1 allowance minus DPCR5 5yrs)	
	£m	£m	£m	£m	%
ENWL	240	244	228	-15	-6%
NPgN	160	163	158	-5	-3%
NPgY	210	221	212	-10	-4%
WMID	270	275	259	-16	-6%
EMID	262	262	260	-1	0%
SWALES	124	125	135	10	8%
SWEST	179	182	212	29	16%
LPN	209	220	221	1	0%
SPN	226	228	215	-13	-6%
EPN	340	344	317	-27	-8%
SPD	194	198	190	-8	-4%
SPMW	227	239	208	-30	-13%
SSEH	123	125	140	15	12%
SSES	271	283	292	9	3%
<b>Total</b>	<b>3,035</b>	<b>3,108</b>	<b>3,048</b>	<b>-61</b>	<b>-2%</b>
<b>Total excl WPD</b>	<b>2,201</b>	<b>2,265</b>	<b>2,182</b>	<b>-83</b>	<b>-4%</b>

## Proposed level of scaling

- 5.34 The proposer is suggesting that the amount of scaling that should be included in the calculation of CDCM credits for eligible embedded generators should be set at 65%. This value is derived as a simple average of the residual scaling as a proportion of the total scaling using the values shown in the table 2 above.
- 5.35 An alternative approach suggested by a Working Group member was to consider DNO specific values that vary year on year to reflect the diversity between different DNO regions.

### What level of scaling as generation credits should be applied?

- 50% of scaling (in line with the initial proposal);
- 65% scaling (in line with the Proposers assessment);
- 0% (in line with the current DCUSA);
- Any other value (if so please indicate what that value is); or
- DNO specific values.

**Please provide your rationale for your choice.**

## 6 Relevant Objectives

### Assessment Against the DCUSA Objectives

6.1 The Proposer considers that the following DCUSA Objectives are better facilitated by DCP 284.

Impact of the Change Proposal on the Relevant Objectives:	
Relevant Objective	Identified impact
Charging Objective Two - that compliance by each DNO Party with the Charging Methodologies facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector (as defined in the Distribution Licences)	Positive
Charging Objective Three - that compliance by each DNO Party with the Charging Methodologies results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the DNO Party in its Distribution Business.	Positive

6.2 The proposer believes Charging Objective Two is better facilitated by DCP 284 because more cost reflective tariffs will provide a more accurate price signal which will result in a more efficient dispatch of plant and the siting of plant within the distribution network. Both of these will result in the promotion of effective competition in generation.

6.3 The proposer believes Charging Objective Three is better facilitated by DCP 284 because they believe it increases the cost reflectivity of tariffs within the CDCM by awarding credits to embedded generators that more closely reflect the benefits they bring to DNOs and thereby encourages the development of efficient, co-ordinated and economical distribution networks.

**Do you consider that the proposal better facilitates the DCUSA Charging Objectives?  
Please give supporting reasons.**

## 7 Impacts & Other Considerations

### Does this Change Proposal impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

7.1 The Working Group does not consider there to be any cross-code impact.

## Consumer Impacts

- 7.2 Consumer impacts will be assessed following feedback from parties. There may be multiple solutions which may potentially increase or decrease the level of credits to embedded generators which could result in a small increase or decrease in cost to demand customers.

## Environmental Impacts

- 7.3 In accordance with DCUSA Clause 11.14.6, the Working Group assessed whether there would be a material impact on greenhouse gas emissions if DCP 284 were implemented. The Working Group did not identify any material impact on greenhouse gas emissions from the implementation of this CP.

## Engagement with the Authority

- 7.4 Ofgem has been fully engaged throughout the development of DCP 284 as an Observer of the Working Group.

## 8 Implementation

- 8.1 The proposed implementation date for DCP 284 is 01/04/2019. Respondents are invited to consider whether they require any further lead time to comply with this change.

## 9 Legal Text

- 9.1 It was identified by the proposer that paragraphs 89 to 95 of schedule 16 of the DCUSA will need to be amended to implement this change. No proposed legal text was provided within the initial CP as the implementation of DCP 228 amends the same paragraphs within the DCUSA. The Working Group note that legal text will be drafted after a review of the consultation responses, to determine the solution of this CP.
- 9.2 The Working Group identified that the CP will also affect the Annual Review Pack (ARP), however will only impact paragraph 1.1 of Schedule 20 of the DCUSA.

## 10 Consultation Questions

- 10.1 The Working Group is seeking industry views on the following consultation questions:

Question Number	Question
1	Do you understand the intent of the CP?
2	Are you supportive of the principles of the CP?



<b>3</b>	Do you accept the interpretation of scaling provided in paragraph 5.11? Provide your rationale for your response.
<b>4</b>	Under the interpretation provided in paragraphs 5.12 and 5.13, should scaling be applied to generation in the same direction as demand (option a), the opposite direction to demand (option b) or neutral (option c)? Provide your rationale for your response.
<b>5</b>	Do you support the view of the proposer provided in paragraphs 5.14 to 5.17 on how scaling is applied? Provide your rationale for your response.
<b>6</b>	Do you agree with the definition of residual scaling provided in paragraphs 5.27 and 5.28? Provide your rationale for your response.
<b>7</b>	Is the current level of capex or the 500MW model a better indication of the avoided cost of embedded generation? Provide your rationale for your response.
<b>8</b>	<p>What level of scaling as generation credits should be applied?</p> <ul style="list-style-type: none"> <li>• 50% of scaling (in line with the initial proposal);</li> <li>• 65% scaling (in line with the Proposers assessment);</li> <li>• 0% (in line with the current DCUSA);</li> <li>• Any other value (if so please indicate what that value is); or</li> <li>• DNO specific values.</li> </ul> <p>Please provide a rationale for your choice.</p>
<b>9</b>	Do you consider that the proposal better facilitates the DCUSA Charging Objectives? Please give supporting reasons.
<b>10</b>	Are you supportive of the proposed implementation date of 1 April 2019?
<b>11</b>	Do you have any other comments on DCP 284?
<b>12</b>	Are you aware of any wider industry developments that may impact upon or be impacted by this CP?
<b>13</b>	Are there any alternative solutions or unintended consequences that should be considered by the Working Group?

10.2 Responses should be submitted using Attachment 2 to [dcusa@electralink.co.uk](mailto:dcusa@electralink.co.uk) no later than **27 February 2017**.

10.3 Responses, or any part thereof, can be provided in confidence. Parties are asked to clearly indicate any parts of a response that are to be treated confidentially.

## Attachments

- Attachment 1 – DCP 284 Change Proposal
- Attachment 2 – Consultation Response Form